INTERIM REPORT ON DISTRIBUTED GENERATION

Prepared by:
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TABLE OF CONTENTS

I. INTRODUCTION

In the second session of the 119th Legislature, the Legislature approved Resolve 1999, ch. 107,[1] which requires the Maine Public Utilities Commission (Commission) to submit a report to the Legislature on or before October 1, 2001 addressing issues associated with distributed generation (DG) in Maine. Because of the complexity of potential issues related to DG, the Commission has produced this interim report to provide background on the status of DG and to establish a basis for a dialogue among stakeholders.[2] The Interim Report will present facts and issues. It will not quantify the effects of DG in Maine nor will it recommend courses of action. It is intended to be informative and non-judgmental, allowing interested persons to better understand the issues that face the State.

The term "distributed generation" does not have a universal definition, but generally refers to smaller-scale generation located near the source of the load it serves. DG is not a new concept, but dates back to the earliest days of the electric industry. For much of the twentieth century, however, small-scale customer-based generation could not compete economically with utility-owned centralized plants. These economics began to change in the 1970s, when centralized fossil fuel plant technology reached maturity and research and development brought forth new technologies such as combustion turbines and fuel cells.

In addition, customers' electricity and energy requirements are changing. Some industrial customers now focus on meeting combined electric and thermal energy needs through one process. Customers such as hospitals and computer-based firms consider power quality and reliability to be requirements, not preferences. Other customers want renewable or environmentally benign power. In response to these factors and to changing federal laws, relatively small-scale generation became common among large industrial customers in Maine, particularly paper and wood product companies, and wind generation developed for a segment of customers who valued its benefits.

The convergence of three events suggests that smaller DG technologies – those below 5 MW - may soon be reasonable options for certain portions of the customer base in Maine. First, new technologies are approaching economic viability. Second, natural gas, the fuel of choice for many DG technologies, is becoming more widely available in Maine. Finally, electric restructuring has heightened customer awareness of electricity generation sources and the wisdom of examining options. A limited number of Maine customers are already

[1] The text of the Resolve is included in full in Appendix 1.

[2] The Commission will, of course, also comply with the legislative directive to file a final report by October 1, 2001.

installing DG of the type studied in this report, and cases testing the policies governing DG appeared before the Commission during 2000.

It is impossible to predict the long-run economic impact of DG. DG could play a small role, serving a limited number of niche markets, or it could become a major part of the electrical supply system through energy campuses and sales into the wholesale market. In either event, the possibility that DG could soon become a mainstream tool requires that regulatory policy take DG into account. The policy questions that the state is likely to address in the near future include:

- What effect should DG have on utility profits and on rates paid by utilities' other customers? In what circumstances should utility revenues lost to DG be shifted to remaining utility ratepayers?

- How should utilities' rates, including standby rates, be designed to accommodate the economic needs of DG owners?

- Should stakeholders develop standardized interconnection contracts to simplify the process a DG facility must follow to connect to the electrical grid?

- Do DG facilities have the potential to reduce electric transmission and distribution costs? If so, what is the best way to ensure that DG will be located and operated in a manner that ensures these benefits can be obtained?

- Are policy changes needed to facilitate DG facilities' sales to the wholesale electric market? Who has jurisdiction over these changes?

- Is it desirable to make it less cumbersome for DG facilities to sell their output to other retail customers, either locally or regionally?

- Should the state allow or encourage utilities to own, operate, or finance DG facilities, either directly or through unregulated subsidiaries?

- Should the state encourage DG as a means of providing customers with an alternative to buying electricity supply from the market and transmission and distribution services from the regulated utility?

- To what extent should environmental ramifications be considered in setting DG policy?

In the remainder of this report, we present facts and define issues that will allow policy makers to consider these questions. For this interim report, our focus is on providing background that will define the questions, not on producing the answers.

II. TECHNOLOGIES

Definitions

The term “distributed generation” does not have a universally accepted definition. For the purposes of this report, distributed generation will mean generation technologies:

- with output of 5 MW or less, with focus on units with output of 1 MW or less;
- located near the source of the load that uses most of the generation output; and
- whose primary purpose is to serve a single customer or a relatively small group of customers.

The DG technologies considered in this report are fueled primarily by natural gas, diesel, solar and wind. They include:

- reciprocating engines;
- microturbines;
- industrial combustion turbines;
- fuel cells;
- photovoltaics; and
- wind turbines.

Some technologies that are arguably distributed resources and share many of the characteristics of the technologies discussed in this report have been excluded from discussion because their benefits, risks and characteristics are generally well-understood in Maine. These include:

- smaller-scale generation built primarily to sell for profit (e.g., small scale hydro);
- large-scale cogeneration of the type used throughout Maine in paper company facilities; and
- demand-side management (DSM). DSM is a distributed *resource,* and shares many of the benefits and risks of on-site generation. Some stakeholders believe that DSM has far more potential than DG to meet load requirements.

Finally, DG can exist on a stand-alone “off-grid” system, but more often is employed as an alternate or supplemental power source for customers who are connected to a T&D utility distribution system. Off-grid applications are common in Maine at remote locations such as camps and as back up power. We focus on the “on-grid” applications in this report.

Technology Characteristics

The Commission has retained Resource Dynamics Corporation to provide a description of current DG technologies. Their report, "Assessment of Distributed Generation Technology Applications," has been issued as a companion to this Interim Report. The technologies description includes functional operation, fuel sources and emissions, generating capacity, capital and running costs, and maturity.

The technologies report also addresses DG's potential benefits to customers including:

- peaking power;
- premium power;
- continuous power;
- environmentally benign power;
- combined heat and power (CHP);
- transmission and distribution deferral; and
- ancillary service power.

III. INTERCONNECTION

Before a new DG facility can begin operation, it must enter into an interconnection agreement with the electric utility. The purpose of the agreement is to avoid safety and operational problems that would impact both the DG facility and the utility grid and to define the commercial relationship between the DG owner (or operator) and the utility. This section will discuss the competing objectives of interconnection activities and the issues faced by utilities and DG operators when carrying out these activities.

Interconnection Agreements

An interconnection agreement (IA) is the contract between a utility and a DG operator that governs the physical configuration and the operation of the DG technology, its interconnection with the grid, and the terms for transferring power to the grid. The agreement is a contract that may be standardized for a group of technologies or that may be unique to each specific DG installation. In some states, the IA must be consistent with regulatory guidelines. The primary goal of an IA is to guarantee that the connection of the DG technology to the utility grid and the connection of on-grid generation to the DG technology maintain the safety and reliability of each. Large generating systems generally require a system impact study before an IA can be reached. Typical contents of a standardized IA are:

- level of on-site utility inspection required;

- o safety equipment requirements;
- o acknowledgement of built-in safety features of some technologies;
- o prices and payment responsibility for interconnection equipment;
- o metering procedures;
- o insurance requirements;
- o technical specifications; and
- o ongoing maintenance.

Nationally, utilities and DG operators understandably emphasize different goals for interconnection agreements. Utilities' primary concerns are the safety and reliability of the grid, while DG operators emphasize the greater speed and lower costs required by a competitive market. While these differing objectives are not mutually exclusive, they create an inherent tension between the two industries.

Many DG advocates claim that IAs are overly complex for smaller generators or generators with built-in safety and reliability features. They claim that utilities unnecessarily conduct on-site engineering studies that are as complex as those required for larger cogeneration projects. IA terms that differ among and within states increase the upfront cost of DG installation. Indeed, many DG owners claim that the cost of the utilities' requirements exceeds the project's profit, and respond by bypassing the utility grid altogether.

Utilities claim that the safety of their lineworkers and the reliability of their grid are too important to compromise. They state that DG owners do not recognize the complexity of the grid and the difficulty of predicting the impact of diverse and uncontrolled generation sources. While system impact studies for large-scale transmission-level generating facilities are well-established, similar studies of DG technologies on a distribution system are more difficult because of the complex interrelationship of changing load, changing generation, and continual upgrades that occur at the distribution level. As more DG is added to a distribution network, these issues become more complex.

In Maine, each utility[3] maintains a relatively simple IA for DG owners who generate 100 kW or less and qualify for net energy billing (net energy billing will be discussed later in this report). CMP and the Independent Energy Producers of Maine, an association of Maine's renewable power producers, recently developed an IA intended for DG technologies of less than 5 MW. Some of Maine's utilities have written procedures and designated contact persons for interconnection activity. Thus, it appears that Maine's interconnection activities are more workable than are those of most states. However, increased simplicity and consistency might benefit all participants by lowering costs.

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[3]In this study, "utility" refers to Maine's investor-owned transmission and distribution (T&D) utilities – Bangor Hydro-Electric Company (BHE), Central Maine Power Company (CMP), and Maine Public Service Company (MPS). The issues are usually, but not always, relevant to Maine's nine consumer-owned utilities.

Interconnection Procedures

Interconnection procedures refer to the steps that a DG owner and the utility must take to connect a DG technology to the grid. In some states, the procedures are formal and governed by regulatory guidelines. Typical steps includes:

- both sides assign a contact person;
- the DG owner provides design specifications for its project;
- the utility performs an engineering study of the impact on grid reliability, safety and costs; and
- the utility and DG operator revise the DG technology's configuration or safety equipment, as both sides become aware of each others' needs.

The issues associated with interconnection procedures mirror the inherent conflict of objectives associated with interconnection agreements. Many DG advocates claim that utility procedures are inherently slow and intentionally obstructionist. It appears that such issues are less contentious in Maine than nationally. Some common claims of DG owners are:

- utilities have a financial incentive not to accommodate a DG request;
- DG owners have no easy recourse for inadequate utility response;
- utility employees are unfamiliar with some technologies and therefore over-study or misunderstand the project;
- utilities do not recognize all built-in safety features of many DG technologies;
- utilities do not have an identifiable contact person or established procedures; and
- utilities demand expensive safety and reliability additions or excessive insurance levels.

Utilities claim that many DG owners do not recognize the complexity of the grid. Some common claims by utilities are:

- protection of lineworkers from electricity backfeeding into the grid cannot be compromised;
- grid operation is extremely complex, with unforeseen impacts from any new generation source;
- black-box technologies have not yet been proven safe and reliable;
- new generation sources might necessitate upgrade to the existing grid or the installation of protective equipment;
- DG owners might not maintain adequate safety and power quality standards;
- scarce utility resources must be used for higher priority projects; and

- o utilities manage the entire grid which becomes difficult if the grid is fragmented by unpredictable and uncontrollable generation. For example, in the 1998 ice storm, re-constructing the grid as a whole might have been far more difficult if the utilities could not anticipate generation scattered around the grid.

FERC activities surrounding development of Regional Transmission Organizations throughout the country might result in region-wide requirements for IA procedures.

National Standards

The Institute of Electrical and Electronics Engineers, Inc., (IEEE)[4] is currently developing national standards governing the interconnections between a utility grid and a distributed generator. The standards are targeted for distribution and voting in early 2001, with adoption anticipated in mid-2001. The standards will include requirements relevant to the performance, operation, testing, safety, and maintenance of interconnections. Most stakeholders believe that, when completed, the IEEE standards can and should be adopted by all states. It appears that states that have adopted standards intend to adapt them to IEEE standards when those become available.

Interconnection Agreement Development

Some states have been successful in forming stakeholder groups to develop standardized IA and procedure guidelines. Maine successfully used this approach during electric restructuring implementation to develop contracts and technical procedures. While the resolution of policy issues requires formal procedures and a longer time frame, it is possible to resolve these more technical issues quickly and through a less formal process. Should Maine wish to develop statewide IAs and procedures, it could begin with those already developed in Texas, New York, and in Maine itself, and with the emerging IEEE standards. Stakeholders could explore this first step without tackling the full array of policy issues associated with DG.

IV. STRANDED COSTS

Stranded Costs in Maine

Maine law[5] defines stranded costs as “a utility’s legitimate, verifiable and unmitigable costs made unrecoverable as a result of the restructuring of the electric industry.” They include, among other things, investments in abandoned

[4]IEEE is a well-established industry consensus standards organization that promotes developing, integrating, sharing, and applying knowledge about electrical and information technologies.

[5]Title 35-A M.R.S.A. § 3208(1).

nuclear power plants and contracts to purchase power from non-utility generators at above market rates. In Maine, the three investor-owned utilities are recovering a significant level of stranded costs over a period of time through the utilities' rates. Stranded costs currently account for 30% - 40% of total delivery prices on average, and will decline gradually over the next 15 years.

Stranded costs strongly influence policy issues regarding DG. As long as stranded costs remain on utilities' books, the loss of revenue from an existing customer that installs DG causes a loss of that customer's contribution to the utility's recovery of stranded costs. In the short term, that loss is absorbed by the utility's shareholders in the form of lower return on investment. In the long term, rates for remaining utility customers must increase if stranded costs are to be fully recovered. Indeed, this phenomenon occurred throughout the past two decades, as many of Maine's larger customers installed larger-scale cogeneration and self-generation. If stranded costs can be eliminated, utilities will be better able to charge economically efficient rates that send price signals that encourage rational customer choice of energy purchase. However, many stakeholders believe that slowing the pay-down of existing stranded costs or introducing new T&D-related stranded costs will jeopardize this effort.

The existence of stranded costs also affects the economics of DG. In the short run, DG benefits from high utility rates that include uneconomic costs. In the long run, utility rates should return to a level that may change the relative economic benefits between DG and on-grid electricity purchase.

In addition to stranded costs, utilities must recover other fixed costs through its rates. Issues and impacts associated with other fixed costs are similar to those associated with stranded costs.

Policy makers must consider whether DG that emerges in the near term will "balkanize" the utility system by removing clusters of customers from the grid and further stranding utility capital investment. On the other hand, if DG emerges gradually, diminishing stranded costs and increasing load may offset the financial harm to utilities caused by DG.

Policy makers considering ways to remove artificial barriers to DG must also consider ways to protect ratepayers without DG or similar options from further burdens caused by stranded and other fixed costs. Balancing this consideration with the legitimate desire of customers to receive the most economic electricity available to them will pose a challenge.

Stranded and Other Fixed Cost Mitigation

There are a variety of ways to avoid increasing the stranded and fixed cost burden for customers still on the utilities' system.

- o Exit fee. An exit fee is a fixed fee charged to a customer that departs the utility system for an alternative power source. The fee collects the amount the customer would have contributed to stranded and fixed costs.[6] Maine law prohibits exit fees for self-generation.[7]
- o Non-volumetric utility price structures. A non-volumetric price structure causes lower revenue loss when a customer installs DG but remains connected to the grid. This concept is discussed later in this report.
- o Utility ownership of DG. If a utility can receive revenue from the departing customer's purchase of alternative power, the utility (and its ratepayers) is partly or wholly insulated from the customer's migration. This concept is discussed later in this report.
- o Economically efficient utility pricing. If delivery is priced close to a utility's marginal cost, a loss of sales is less harmful to the utility and is economically efficient from a societal standpoint.

None of these actions is a panacea for balancing the needs of DG owners against the needs of utilities and their ratepayers. For example, exit fees and non-volumetric pricing avoid increasing utility rates, but discourage DG development. Utility ownership of DG and its generation partially reverses the unbundling of generation and delivery functions accomplished by Maine's restructuring law. Setting utility rates at marginal costs does not allow recovery of stranded costs in the short term and is generally not achievable in the presence of stranded costs.

V. UTILITY PRICING

One of the principal tools for dealing with stranded costs and economic inefficiencies is utility pricing and rate design. Utility rate design can be a means for avoiding loss of DG customers' contribution to stranded and other fixed costs, but can also be a deterrent to DG. This section describes several pricing strategies that will influence the penetration of DG in Maine.

Utility Price Level

Currently, the price of utility delivery service is relatively high in Maine when compared to other regions. As discussed earlier, a significant portion of that price is attributable to stranded cost recovery, which will diminish over time. Price comparisons may thus be different in the short run and the long run. In the short run, DG technology benefits from higher utility rates. However, the existence of stranded costs in utility rates induces uneconomic bypass because electricity price is above marginal costs whereas alternative energy sources may be priced close to margin. In the long run, to the extent that utility prices more

[6] There are variations to this approach.
[7] 35-A M.R.S.A. § 3209(3).

closely mirror the underlying cost structure, customers will be induced to make economically efficient decisions between DG and utility service.

Energy Price Level

The wholesale price of competitive energy is unsettled in New England. During 2000, ISO-NE's[8] clearing price generally ranged from 2 cents/kWh to 6 cents/kWh, but experienced periods of spikes as high as $6.00/kWh. This behavior leaves customers uncertain of the future price of electricity, causing some customers to avoid changing energy sources until greater stability allows more certain cost benefit analyses. Other customers may consider the relative certainty of owning their own generation source to be an advantage in this market.

In addition to the uncertainty of the electricity market is the uncertainty of the commodity gas market. The price of natural gas has increased dramatically during 2000, fluctuating between $4.00 and $12.00. While prices have declined in the early part of 2001, it is reasonably likely that they will remain volatile. In addition, some customers' natural gas commodity can be interrupted. Thus, customers considering one of the many DG technologies fueled with natural gas are faced with considerable uncertainty regarding the operating cost of the technology. This uncertainty appears to be having a dampening affect on DG investment in Maine.

Utility Price Structures

The utility price structure (as opposed to the overall price level) significantly influences the viability of DG alternatives. Volumetric pricing (i.e., a high cent-per-kWh price and low fixed charge) makes off-grid generation, coupled with continued back-up attachment to the grid, attractive. Under this form of utility pricing, a customer avoids a high portion of its T&D utility bill every time it generates electricity from on-site generation. Alternatively, a fixed-price utility rate structure makes on-site generation less attractive for a customer remaining on the grid, because the customer avoids very little of its utility bill every time it generates electricity from its on-site source. Currently, utilities' pricing structures feature relatively low fixed-price charges and relatively high per-kWh charges. In addition, some customers also pay a demand charge based on their highest use in the month. In general, demand charges can also be avoided by use of on-site generation, but this requires the customer to pay careful attention to each hour's usage level. The demand ratchet that tends to act like a fixed-price component has been eliminated from all but BHE's rate structures.

With restructuring, utilities across the country are considering increasing the fixed portion of their rates and lowering the volumetric charge to reflect the

[8] ISO-NE is the bulk power system administrator in New England.

underlying cost structure of a delivery-only system. Delivery system costs are driven by the capital costs of building the infrastructure and therefore are not significantly sensitive to volumetric changes. Utilities comment that the current volumetric price structure allows uneconomic bypass. The extent to which changes will be made to utility price structures is uncertain. In Maine, the Commission will conduct rate design proceedings during 2001 to determine the appropriate future price structure for Maine's utilities.

Finally, the manner in which a utility charges for line extensions may affect the attractiveness of DG. To the extent that the customer benefiting from the extension must pay its costs, the customer may be inclined to consider DG in lieu of being connected to the grid. To the extent that those costs are shared by all ratepayers that incentive disappears, even though DG may be the less costly alternative.

Unique DG Pricing

Some policy makers have decided that DG technologies should not include the portion of delivery rates that account for stranded cost recovery. For example, in New Jersey, DG is exempt from the competitive transition charge (CTC) as long as DG comprises less than 7% of the utility's load. This approach is sometimes used for DG serving new load, reflecting the argument that new load is not responsible for causing stranded costs.

Standby Rates

Standby rates are utility rates that a customer pays to deliver power from the grid at times when its own DG is unavailable.[9] The cost of standby delivery strongly affects the economic viability of the DG technology in instances when the customer cannot or chooses not to disconnect from the grid. Because disconnection from the grid requires that a customer maintain its own backup power source and follow its own load precisely, most customers are likely to find grid attachment to be the more attractive option. Thus, standby rates have become a significant point of discussion in the DG community.

It is generally agreed that standby rates should reflect the cost to the utility of providing standby service, thereby allowing a customer to make an economically efficient choice between alternative forms of electrical generation. However, determining a cost-based rate has proven difficult. Data regarding the impact that standby customers have had on utility systems has been inadequate, and opinions on the best application of that data have differed widely.

As with utility rates in general, a standby delivery rate may be volumetrically priced, or may include a high fixed charge and low per-kWh

[9]Theoretically, standby rates apply to generation purchases as well, but the national debate focuses on delivery standby rates.

charge. Utilities argue that standby rates, even more so than core rates, should include a high fixed charge. The customer is reserving the ability to deliver a certain generation amount over the T&D system, but will use that system for a short period of time. The T&D system must be built and maintained to accommodate the customer's maximum load, so the utility must charge a rate based on the customer's maximum load requirement if it is to recover its costs.

In instances when a utility customer with DG technology uses the delivery system only sporadically, it is argued that the customer's rates should not reflect its entire load because the customer will not necessarily require delivery at the time of the utility's local or system peak. If an individual DG operator requires delivery at a time of low system use, then the operator causes the utility to incur very little, and perhaps no, additional cost. Thus, standby rates might reasonably reflect non-coincidence of DG use of the T&D system.

In Maine, the rate structure for CMP's standby rates remained constant (and generally un-examined) for many years. Customers usually paid for standby service at the core rate. Until recently, the existence of a demand ratchet in the core rate caused standby service to be quite costly if only used a few times per year.[10] At the time of electric restructuring, the Commission intentionally left the effect of standby rates on customers unchanged to avoid onerous rate impacts, by maintaining the existing standby rate and retaining ratcheted core rates for standby purposes. In early 2000, standby rates for some customers were revised to eliminate the ratchet feature, thereby effectively making it a more volumetric rate and lowering the overall price for most customers.

In summary, at this time Maine's standby rates appear to be less onerous than those of many states but may nonetheless be costly enough to discourage some DG installation. It is unclear whether the rates are uneconomic. Because standby rates and core rates are directly related, examination of standby rates will be done at the time of a core rate design proceeding and will likely occur in Maine during 2001.

Pricing Flexibility

In Maine, utilities may lower rates to single customers or groups of customers so long as the lower rate still exceeds the utility's marginal cost to serve the customer(s). Utilities may exercise this authority in instances when a customer would replace on-grid electricity with its own on-site generation absent the price reduction, thereby eliminating revenue that the utility had been receiving. Maine's utilities can and do offer price reductions to high-volume

[10]The demand ratchet requires that a customer pay a demand charge based on the higher of its current month peak demand or 80% of its highest monthly peak demand in the prior 11 months. (variations exist). This charge becomes essentially a year-long fixed charge based on the customer's maximum load.

customers who demonstrate a high likelihood of installing DG, although the price reduction applies to only the non-generation portion of the electrical cost. Because utility costs are driven by capital investment, short-term marginal costs are extremely low in instances when the T&D system is in place and adequate. Because utility rates contain a high stranded and fixed cost component, the utility price reduction is often significant and undercuts the price of the DG technology. In theory, the reduced but above-margin utility price sends a more economically efficient price signal to the customer choosing between two electric generation sources. It appears that in the near term, utilities may be able to compete effectively on price except in instances when the customer requires a significant line extension or upgrade or when CHP creates benefits from DG that extend beyond electricity price.

Transmission Pricing

Because DG technologies are located close to a load source, they may reduce line losses on the utility grid. Some stakeholders urge that this should be considered when setting delivery prices for DG power that is carried over utility wires or through some other mechanism. In addition, if a generation source located on a non-PTF facility but serving load beyond that non-PTF facility must pay wheeling charges to reach PTF facilities, the generator is placed at a competitive disadvantage based on its unavoidable location. Regional organizations and the Federal Energy Regulatory Commission (FERC) consider these arguments when setting transmission rates.

Locational Pricing

In a later section, this report describes the benefits of DG to the T&D system. As described there, a DG technology may improve the efficiency of the utility grid, thereby reducing the cost of the grid to all utility ratepayers. Alternatively, a DG technology may have the opposite effect, delivering load on a portion of the grid that cannot accommodate it. For example, the local distribution grid may be loaded at its capacity, or a loop system may contain network protections that detect flows from generation to customers and are incapacitated when generation is introduced at the customer location. DG can also create power quality deterioration. In such instances, DG is detrimental to the efficiency of the grid, thereby increasing the cost to all utility ratepayers.

Currently, there are no price signals that encourage open market participants to install DG in locations that benefit the distribution grid and avoid locations that are detrimental. The law prohibits delivery prices from being locationally differentiated, and public opinion regarding such pricing would likely be unfavorable. One way to provide price signals that reflect grid cost would be for utilities to designate distribution congestion zones where distribution is constrained. Utilities could provide credits or waive stand-by fees for generation built in these areas. The zones and the level of credits would change regularly, as the configuration or condition of the distribution system changes. This approach would be symmetrical with the utility's ability to lower rates to customers when DG would be detrimental to the utility. Although this idea has been discussed, it does not appear to have been implemented in any state, and it may not be workable at the distribution level because of the difficulty of developing separate and stable costs for each portion of the distribution grid.

Compounding the difficulty of offering appropriate distribution-related price signals is the fact that the peak load at one portion of the grid may occur at a different time than the system peak load. Thus, market energy prices and utility delivery prices might cause customers to use DG to shave peaks at a time that is unrelated to the most efficient local grid peak-shaving period. This is another instance in which locational pricing would be necessary to induce T&D grid efficiency.

Finally, another possibility is to require utilities to solicit bids for DG solutions before upgrading a line. This process would incorporate lower-cost DG into utility planning, in instances when it exists. Like price credits, this suggestion does not appear to be used in any state.

Price Cap Regulation

Maine's largest utility operates under a price cap plan, which provides for annual rate changes by an amount that reflects inflation less a productivity offset. The Commission does not conduct a rate proceeding until the plan expires. Under price cap regulation, any incremental savings or costs are borne by shareholders during the pendency of the plan. Thus, the utility has a strong incentive to operate efficiently, but a strong disincentive to lose sales to DG, because the lost profits from those sales cannot be recovered from ratepayers. As policy makers consider the effect of DG on utilities and ratepayers, they must differentiate between effects in the short run – the pendency of the price cap plan – and the effect in the long run. Before the plan expires, utility revenue gains and losses impact shareholder returns. When the plan expires, gains and losses will be incorporated into ratepayers' rates in a manner that will be determined in a rate proceeding.

VI. SELLING GENERATION

Currently, most of the DG facilities considered in this report are sized to meet some or all of the electric requirements of a single customer. However, there are situations in which a customer wishes to sell electric power which is surplus to his or her own needs. The possibilities for doing so include occasional incidental sales, facilities intended to serve multiple customers, and facilities that sell a major portion of their output on the wholesale or retail market. This section discusses the issues associated with those sales.

Load-following Generation

DG technologies are often designed to follow load. This means that the generation equipment physically connects to the building's energy management system, detects the load level of the building, and generates the amount of electricity the building needs at all times. Technologies have been developed with this load-following ability to avoid buying electricity from the grid[11] and to avoid the administrative costs associated with selling excess electricity into the grid.

Small Amounts of Excess Generation – Net Energy Billing

Net energy billing (or net billing) is a procedure that allows a small on-site generator to feed small amounts of excess power onto the grid under a simple accounting procedure.[12] Net energy billing in Maine is targeted to residential customers who intend to serve a portion of their own load, but whose on-site generation is unable to follow that load. It is not intended for use by facilities that generate for the primary purpose of selling power. In Maine, the utility measures the amount of power drawn from the grid and the amount fed into the grid each month. If the amount fed into the grid exceeds the amount drawn from the grid, the net excess is banked and applied to future months. At the end of a year, the customer loses what has been banked. Thus, the customer receives an advantage from its excess generation but cannot use it as a profit-making enterprise. Net billing is available to customers with generation of 100 kW[13] or less. Approximately 35 customers currently use net billing. Most are wind generators that are far smaller than 100 kW.

Currently, the amount of generation feeding into the grid from net billing is minimal and does not impact grid reliability. Raising the 100 kW level would allow DG technologies to operate more economically[14] while taking advantage of the simplicity that net billing offers. However, it would increase the unaccounted-for generation into the ISO-NE power grid and the unplanned generation interaction with the utility grid. At this time there is no known level at which such unplanned generation would become a problem for the ISO or the utility, making it difficult to judge whether increasing the 100 kW breakpoint would be problematic.

Sale into the Power Pool

Some emerging DG technologies avoid creating excess generation because they follow load. Those technologies that cannot follow load precisely

[11] This is particularly important if the customer is disconnected from the grid.
[12] In Maine, procedures are governed by Chapter 313 of the Commission's Rules.
[13] A residential household load ranges from 1 to 15 kW.
[14] Indeed, the overall cost of some technologies such as wind generators drops dramatically when higher generation output occurs and economies of scale are realized.

often limit generation production to a level that allows use of net energy billing. However, most technologies would benefit from the economies of scale created from higher levels of generation output. Currently, such installations would be required to sell their excess generation into the New England Power Pool.

Generation owners that sell their generation to the power pool are wholesale providers. They must conform to ISO-NE or NMISA[15] requirements, and they are regulated by the FERC.[16] ISO-NE allows three arrangements for sale of generation. First, the generator may become a member of the New England Power Pool (NEPOOL), requiring annual dues that are prohibitive for small-scale generators. Alternatively, the generator may contract with another generator who is a NEPOOL member, and include its load with that of the member. At this time, it appears that it is difficult to find a NEPOOL participant who will purchase power from a small generator, despite the fact that many of these small generators supply energy that meets Maine's resource portfolio requirement. It is difficult to determine whether, as the market matures, this type of arrangement will become easier.

Finally, a generator of less than 5 MW may sell directly to the pool rather than through another participant, under less complex procedures. It need not bid, but may be a price-taker, meaning that it simply sells its power at the clearing price. It need not have real-time hourly metering, but may carry out ISO-NE's financial settlement based on loads read after-the-fact from hourly meters. It appears that ISO-NE recognizes the need to develop workable procedures for small generators but has not yet completed that task.

In the near future, other mechanisms may facilitate small generators' participation in the New England regional market. Recently, ISO-NE announced a pilot program in which small generators and demand-side load control programs receive payment for providing reserves or power during high-cost hours. Such programs are likely to expand as the market matures.

Sale to Retail Customers

Because economies of scale occur when technologies produce larger amounts of generation, DG often becomes more viable if it can sell its generation directly to other retail customers. This could take a variety of forms, some off-grid and some on-grid, including:

- sale to immediate neighbors;

[15] ISO-NE is the bulk power system administrator in New England. Northern Maine is not part of New England's bulk power grid, but is part of the Maritimes Control Area. NMISA is the bulk power system administrator operating in Northern Maine. Throughout this report, references to ISO-NE may be extended to the NMISA.

[16] Thus, they face the same conditions as the small-scale hydro and wind generators that are not subject to this study.

- o sale to customers elsewhere in the state – e.g., sale to all stores in a chain;
- o sale to a business associate, located nearby or elsewhere; and
- o sale to a business complex – e.g., on-site generation serving a shopping center or industrial park.

Currently, very little activity of this type is occurring in Maine. These arrangements raise a variety of questions that are not yet clearly answered, in Maine or elsewhere:

- o If the generator sells to its neighbors or others, is it a competitive electricity provider?
- o If the generator or its customer builds transmission facilities to carry power from one to the other, is either a public utility?

Under Maine's law, a competitive electricity provider is defined as "a marketer, broker, aggregator or any other entity selling electricity to the public at retail" and is subject to operational and reporting requirements established by law and by Commission rule to protect consumers and the operation of the market. These include Maine's 30% resource portfolio requirement, uniform disclosure label provisions, licensing procedures, consumer protection rules, and customer enrollment and billing procedures. In addition, ISO-NE rules require a competitive provider to participate in daily load settlement procedures by which ISO-NE matches the generator's generation to its load obligation. Under this system, the generator must meter its hourly loads, provide ISO-NE with its daily predicted load obligations, and carry out financial transactions with ISO-NE based on its customers' estimated hourly consumption.[17] A small-scale generator is likely to find these legal and regulatory requirements prohibitively complex and expensive.

If the settlement occurred directly between seller and buyer, without involving ISO-NE, the settlement mechanism must contain the basic features of the ISO-NE procedures to allow accurate financial transactions to occur. A settlement that simply matches monthly kWhs generated with those sold may be feasible for small levels of load. However, the need to maintain a reliable generation level on the grid remains, and requires regional coordination at some level.

A DG facility that sells to retail customers appears to fall within the definition of competitive electricity provider as long as the sale is to the public. However, cases have appeared before the Commission testing the boundaries of the definition. For example, Maine law exempts sales to a generator's affiliate from the requirements otherwise applicable to providers. In addition, the

[17] As described earlier, a retail provider may include its load with that of another NEPOOL participant for purposes of ISO-NE procedures. However, the provider must nonetheless comply with Maine law and rules.

meaning of sale "to the public" is being tested. As with many issues associated with DG, scale is relevant. Actions taken on a small scale may be benign, but proliferation of such actions may result in grid imbalances, inaccurate financial settlement for remaining generators and customers, and increased stranded and other fixed cost burdens on remaining utility customers. Clearly defining the conditions under which a DG technology is a competitive electricity provider under the law would eliminate an uncertainty faced by DG developers. It is likely that generator activity will result in additional test cases in the near future, allowing the Commission to more clearly delineate the boundaries of the definition.

Under Maine's law, a public T&D utility is defined as "a person… owning, controlling, operating or managing a transmission and distribution plant for compensation within the State…" and is subject to regulation pursuant to Title 35-A of Maine's law. A DG owner wishing to transport electricity to other businesses or households in its geographic vicinity may fall within this definition. To date, there are few instances of generators attempting this type of arrangement. However, a small-scale generator that is judged to be a public utility would require Commission authority to deliver power and would find the legal and regulatory requirements to be burdensome and costly. In some cases, the Commission has found that an entity serving a small number of customers, under conditions that retain consumer protections, is not serving the "public" and therefore is not a public utility.[18] Extensive precedent does not exist in the electric industry, but will likely be developed as cases arise.

VII. DISTRIBUTED GENERATION AS A TRANSMISSION AND DISTRIBUTION TOOL

Thus far, this report has treated DG as a generation source. However, DG can also provide benefits and risks to the T&D system infrastructure. Beneficial applications can lower the overall cost of the utility system and thus lower rates for utility customers in the long run. With this in mind, the electric restructuring statute allows utilities to own generation when such ownership is necessary to carry out the utility's T&D obligations.[19]

Consideration of DG as a utility tool is important for two reasons. First, it helps frame the question of whether and when a utility should be authorized to own DG. Second, it offers a broader perspective on the emergence of DG. DG that is beneficial to a customer may be beneficial or detrimental to the utility and its ratepayers. This unpredictable effect complicates the policy issues associated with adopting DG.

[18]For example, Kendall Lake Shore Ass'n. M.221 (Jan.31, 1980) articulated a seven-part test to use in this situation. Currently pending dockets 2000-653 and 2000-654 are addressing instances involving electricity delivery.

[19]35-A M.R.S.A. § 3204(6). This generation is not generally dispatched in the same manner as generation used to serve customers' loads.

DG may be a cost-effective T&D tool in the following circumstances, which will be discussed in subsequent paragraphs:

- to avoid T&D distribution system upgrade in a growing region;
- to provide voltage support on a distribution line;
- to avoid T&D line extension upgrade to a single customer;
- to avoid a line extension altogether; and
- to provide balancing support.

Traditionally, when a region's load grows to the point that the existing distribution line becomes undersized, the utility upgrades the line by re-conductoring, rebuilding the line, or building new lines into the area. System upgrades are costly and may be difficult to accomplish in a crowded urban area. A variation of this situation is a transmission congestion point, in which an entire city or area cannot receive adequate generation beyond the congestion point. In these instances, a DG technology can be placed near the customers' load, thereby providing the needed electricity without requiring delivery of that electricity over a line that cannot accommodate it. The fact that DG is removable increases its value as a distribution tool, because it can be moved to a new location after it is no longer useful. It appears that larger-scale DG (5 MW or greater) is necessary for this purpose, and utilities have not considered DG for this purpose until recently because of the immaturity of the technologies. However, should installation of a DG technology be less costly than a line upgrade, the utility and ultimately its ratepayers would benefit by its installation.

DG can also provide voltage support to the electrical grid in areas of weak voltage such as remote locations. The DG can be sited at the end of a line, thereby lowering voltage loss over the entire line. The DG is manually operated when the utility detects low voltage in the area, which would occur sporadically. Therefore, the DG is designed and operated for occasional use and need not provide the full capacity level required by the area. Because of this design, the DG does not have the appropriate configuration to serve the full baseload needs of all customers when the grid is down. In addition, although the DG is the lower-cost means of providing voltage support to the grid, it is not economical on a stand-alone basis. Thus utility ownership may be the most appropriate model for this application.

If a single customer's load increases, the line extension delivering energy to that customer may become undersized. Similarly, if a customer's business operations require higher quality than is traditionally delivered by the utility, an upgrade to the line extension feeding the customer is warranted. In these instances, the customer is likely to be responsible for the cost of the upgrade. DG technology on the customer's site might be a more economical alternative. Indeed, this situation is a common driver for customers to install DG themselves. However, it is reasonable to suggest that the utility could offer the DG, on the customer's side or the utility's side of the meter, as an alternative to its traditional approach of a line upgrade.

Traditionally, if a single customer builds a new facility in an area remote from the delivery grid, the utility provides a line extension at the customer's expense. Building (as opposed to upgrading) a line extension is costly for a remotely located customer, and is particularly prevalent in the rural portions of Maine. Again, this situation is a reason for customers to install DG – e.g., a diesel generator – themselves. Such a DG application requires an operating efficiency and peak load capability adequate for the customer's full service needs, and customers do not generally favor this solution. The utility might offer DG as an alternative to the traditional line extension.

On the other hand, DG can exacerbate problems caused by excess generation, especially in the regions in Maine where export transmission is constrained. In addition, DG may require redundant units to maintain adequate reliability.

Finally, there are claims that DG can prove useful in providing kilovar support on the grid, although currently this application appears to be limited.

In conclusion, there are a variety of instances when DG might prove a lower-cost solution to managing the T&D system, irrespective of its benefits to a particular customer. Policy makers nationwide are attempting to recognize and quantify beneficial impacts on the T&D system and incorporate them into procedures and policies.

VIII. BROADER POLICY CONSIDERATIONS OF DISTRIBUTED GENERATION

In this section we consider broader policy considerations related to DG as a widespread generation source.

In other states, the most compelling reason to encourage DG has been to avoid building new central generating plants in regions with insufficient generation capacity. This use of DG has been the driving force behind the speed with which Texas, New York and California have developed rules to encourage DG. Maine operates within a single New England-wide regional wholesale generation market in which capacity is currently adequate, so this objective is less compelling as a policy objective in Maine.[20] However, ISO-NE is in the process of developing pricing mechanisms that respond to transmission constraints. Because constraints are minimal on transmission into and within Maine, this is likely to result in lower prices in Maine than the rest of the region,

[20] Five newly-constructed gas-fired electrical plants are scheduled to produce 1,500 MW of generation, an amount approximately equal to Maine's entire load. The extent to which DG can fulfill Installed Capability (ICAP) requirements is uncertain.

making DG less economically attractive in Maine than would be the case if transmission into the state were constrained.

However, most DG technologies have lower fuel emissions than existing coal and oil-fired generating plants. Wind and solar DG emit no harmful emissions, and technologies fueled by natural gas emit CO_2 at a rate below that of oil and coal plants. Thus, to the extent that DG replaces older, dirtier plants, DG would provide environmental benefits to the region. In Maine, the 30% resource portfolio requirement is the primary means to encourage the use of environmentally benign generation.[21] It is unlikely that retail marketers would use DG facilities of the size addressed in this report to meet their resource portfolio requirement, but it is too early in the restructuring process to know with certainty.[22] Early anecdotal evidence indicates that the market for renewables is not operating effectively in the early days of restructuring. However, the implementation of a planned regional Generation Information System (GIS), as well as the increased experience of the participants, may cause improvement in market efficiency and increased opportunities for DG participation.

An interesting aspect of DG is that some technologies are environmentally benign, while others - in particular, diesel generation - cause significant environmental harm, including noise pollution. In addition, emissions levels of small engines generally are not regulated. Policies that eliminate barriers to adoption of DG generally affect all types of DG similarly. Stakeholders who support DG for environmental reasons must consider the extent to which policy changes encourage both types of technologies.

Finally, developing fuel and technology diversity through DG development will guard against the risk of price spikes in individual fuels, and will produce a healthier generation mix in the long term. The emergence of DG may create fuel diversity by increasing wind and solar as generation sources. On the other hand, the technologies most likely to emerge in the near future are fueled by natural gas, and thus, when combined with the construction of gas-fired central plants in New England, the emergence of DG might *reduce* fuel diversity. It is unclear to what extent this should be a concern now that Maine has moved to a competitive generation market.

IX. OWNERSHIP OF DISTRIBUTED GENERATION

As discussed above, distributed generation can be both a source of generation and a means to improve a delivery grid. Consequently, in states in which unbundling has occurred, a debate exists as to whether utilities should be authorized to own or operate DG. In Texas and New York, both states that have

[21] 35-A MRSA § 3210 and Chapter 311 of the Commission's rules.

[22] On March 1, 2001, marketers must file a report with the Commission demonstrating their compliance with the resource portfolio requirement. These reports might provide evidence of the requirement's impact on DG owners.

unbundled, utilities may not own DG. However, it is not clear that this approach will prevail nationally or indeed in those two states under all circumstances.

Maine Law

Maine's electric restructuring law states that investor-owned utilities may not "own, have a financial interest in or otherwise control generation or generation-related assets."[23] Full unbundling of generation from delivery was a critical cornerstone of Maine's restructuring approach.

However, the law makes an exception when "the commission finds that ownership, interest or control is necessary for the utility to perform its obligations as a transmission and distribution utility in an efficient manner." [24] Pursuant to this provision, BHE currently owns diesel generators that are used to support voltage on the delivery route to Eastport and Bar Harbor. This exception clearly opens the door to utility ownership of some types of DG. The extent to which this type of generation was envisioned by the Legislature or would be allowed by the Commission has not been probed.

Utility Ownership

Authorizing utilities to own DG has four primary benefits:

- o encourages use of DG in situations that are economically efficient for the delivery grid, thereby benefiting all customers;
- o partially mitigates the risk that DG shifts stranded and other fixed cost to remaining utility customers;
- o speeds up market penetration of DG; and
- o ensures that DG is operated in a manner beneficial to the grid.

Ownership has four potential risks:

- o partially unravels the separation of the T&D and power supply functions that is at the core of restructuring;
- o adds a market barrier to entry by non-utility sellers of DG;
- o risks market power in remote areas; and
- o requires greater regulatory oversight to protect against unfair competition.

The benefits and risks are discussed below and in the next section of this report.

As discussed above, DG may sometimes be the lower-cost means of relieving congestion or delivering electricity to a remote location. The economics of using DG for this purpose are location-specific and often difficult to quantify.

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[23] 35-A M.R.S.A. § 3204(5).
[24] 35-A M.R.S.A. § 3204(6).

The utility is the only entity capable of calculating the economic benefits of a DG application to the electric grid. Mechanisms to provide price signals to non-utility DG investors are non-existent today and may be difficult to develop in the future (locational pricing was discussed earlier in this report). Allowing the utility to install DG as part of its normal grid maintenance is thus the most straightforward way (and perhaps the only way) to ensure that the technologies are installed in the most efficient instances. In some cases, utility-owned DG would serve a single customer and operate in the same manner as if the customer owned and maintained the technology. In other cases, the technology would serve many customers and would operate as part of the overall grid.

As discussed earlier in this report, when a customer installs a DG technology on the customer's side of the meter, the utility loses delivery sales, thereby losing the customer's contribution to fixed costs under traditional rate structures. The resulting fixed costs must be borne by the utility shareholders (in the short run) and the remaining customer base (in the long run). Allowing the utility to own or operate the technology gives the utility a means of collecting revenue that partially offsets the loss of delivery sales to existing customers or adds incremental contribution to fixed costs in the case of new load. In addition, the utility may choose to install the technology on the utility side of the meter, thereby retaining some level of delivery sales revenue.

Many stakeholders believe that allowing an entity with a strong presence in the energy community to become active in the DG market will accelerate market development to the advantage of all participants. Allowing utilities to use DG in instances when individual customers would not adds additional benefits to the DG market.

On the other hand, allowing utilities or their affiliates to own DG might begin to unravel the unbundling process that is the cornerstone of Maine's restructuring law. One way to allay this concern is to confine the level of authorized DG ownership to a small percentage of utility load. New Jersey and Massachusetts have implemented DG-enabling provisions that apply only if DG load is below a pre-defined level, although such a limiter does not appear to apply to utility ownership. Another means is to limit ownership to inventory for sale or lease only.

Stakeholders are also concerned that utilities are such dominant entities in the energy community that they will foreclose entry into the DG market by other entrants. Other stakeholders comment that the market is diverse, with many players already, and that there are many participants that are far larger or more dominant than utilities.

Models for Utility Ownership

When considering utility ownership, two situations must be differentiated. In the first, the utility owns a technology that benefits a portion of the grid. This situation is not a replacement for customer-owned DG, and would not occur as a result of solely market-driven forces without the development of locational pricing or credit mechanisms. In the second situation, the technology provides generation (not delivery) to a customer or customers, and alternatively might be installed by the customer itself. For this report, we will call the first situation "grid-support" and the second situation "customer-support."

Stakeholders have suggested a variety of models that allow utility involvement in DG. Four models are discussed below. Each may be considered as a model for a utility or for an unregulated affiliate.

First, the utility might own, operate and maintain the DG technology in the grid-support situation discussed above. In this model, the technology is treated like any other grid investment. The utility earns a return on its capital investment and recovers the cost of operation and maintenance through its rates. The utility or a third party takes title to the power, selling it into the grid. This model encourages lower-cost investment in the utility grid, introduces technologies more quickly than would occur otherwise, largely preserves unbundling, and does not appear to interfere with open market participants who are selling technologies to individual customers for their own generation.

The same model could be used in the customer-support situation. The utility earns a return on its capital investment, and charges a fee to the customer that includes a mark-up above the utility's operation and maintenance costs, thereby partially offsetting lost delivery revenue. The utility would take title to the power, selling it to the customer. This model lowers rates to utility ratepayers in the long run, because the utility receives revenue to offset its fixed costs. However, it partially unravels unbundling by putting the utility back into the electricity sales business. It might introduce technologies more quickly by adding a large player to the market, but may reduce market opportunities for new entries.

A second model has the utility simply selling the DG technology to a customer, without retaining ownership of the technology or the power it produces. This model lowers the risk that unbundling will unravel because the utility does not own and sell generation. It lowers the risk that the utility will dominate the market, since the utility does not offer energy services associated with the technology. It allows the utility to profit from the sale, partially offsetting lost delivery revenues. This model is only viable in the customer-support situation, and may be better suited to unregulated affiliate ownership.

A third model has the utility operating as an energy service company that operates the DG technology. Customers who wish to concentrate on their core business, not generating electricity, are likely to find this option attractive. This model is viable in the customer-support situation, and may be better suited to unregulated affiliate ownership.

Finally, a fourth model allows the utility to lease DG facilities to customers. The utility would own the technology but not operate or maintain it. The model offers customers "off balance sheet" treatment, allowing them to avoid upfront investment in an asset that does not have the short pay-back period often required for corporate investments. This model is also viable in the customer-support situation and may be better suited to unregulated affiliate ownership.

Affiliate Ownership

The risks associated with utility ownership or operation are reduced by requiring the activity to be carried out by a utility's unregulated affiliate. Maine law allows an affiliate to market but not own generation, and places limitations on market share. Thus, unlike the utility, an affiliate may already operate in the energy market. Both state statute and Commission rules establish strict codes of conduct between the affiliate and the utility that would minimize the affiliate's market advantage over other participants in the DG market. The question of whether allowing ownership of a generation technology jeopardizes Maine's restructuring model remains an area of concern. One way to address this concern is to impose limits on an affiliate's level of DG ownership in the same manner that the law limits an affiliate's level of electricity sales.[25]

The four models discussed in the previous section – full ownership and operation, sale-only, operation-only, or lease -- may be considered for affiliates.

Stakeholders argue that prohibiting an affiliate from owning DG places it at a competitive disadvantage in the market it serves. Electricity marketers and energy service companies can offer DG as a tool to satisfy customers' energy needs; under current law, the affiliate operating in the same market cannot. As DG becomes increasingly economical, this disadvantage could severely limit the affiliate's ability to remain economically viable.

Along with reducing the risks associated with utility ownership, affiliate ownership also reduces the benefits. Because the affiliate operates like all other market participants, it does not have the knowledge or inducement to invest in grid-support DG, and it might introduce DG in locations that are detrimental to the grid. It is not likely to introduce technologies any faster than other participants. However, its presence will speed technology introduction simply because it is one more viable player in the market.

[25]CMP and BHE's affiliates' sales would be limited to 33% of the utility's service territory. MPS's affiliate has no such limit.

Under current rules, affiliate ownership of DG would not mitigate the impact of shifting stranded and fixed costs to other utility ratepayers because gained or lost profits could not accrue to utility ratepayers. A way to attain this benefit is to allow an affiliate to share its return with its affiliated utility, thereby partially offsetting lost delivery revenue.[26] This approach has the disadvantage that it is inconsistent with the current Maine model whereby affiliates' operations and financial results are kept strictly separate from those of the utility. The extent to which cherry-picking the affiliate-utility separation rules, by allowing sharing of operations or finances in some situations and not others, introduces significant disadvantages is not clear. For example, it would seem reasonable that, if the affiliate shared its gains with the utility it would also share its losses, an outcome that is unlikely to be desirable.

Finally, there is a potential unintended consequence of allowing affiliate ownership of DG that could be undesirable to utility ratepayers. Shareholder benefit from affiliate-owned DG is not limited to a regulated rate of return. To the extent that profit earned by the unregulated affiliate can exceed the return earned by the regulated utility, there is an incentive to transfer activity to the affiliate. For example, if the utility ceased offering price reductions to retain customers with a DG option, and the affiliate provided the DG option, shareholders would lose only the small margin earned from a reduced-price delivery sale, but would gain the margin on the DG technology and electricity generation.

This concern might be unfounded in Maine. First, for this to occur, the affiliate must be certain of the DG sale, which it could not be if the market is healthy and strict codes of conduct prevent the utility and the affiliate from sharing knowledge or business plans. Thus, the problem may be avoided by strict enforcement of the codes of conduct. In addition, a utility operating under an alternative rate plan would generally be able to retain the same DG profits as could its unregulated subsidiary, thereby eliminating the concern altogether.

X. ACTIVITY ELSEWHERE

Distributed generation has received significant attention at the national level and in some states. States have focused on DG primarily to avoid capacity shortages. Nationally, attention has focused on the policy issues of environmental impact, reliability and affordability, and on actions that will remove barriers to DG development. Because Maine policy makers can use procedures in other states as a starting point for their own decision-making, this section will discuss activities elsewhere.

[26] Note that lost delivery revenue and cost shifting do not occur when the affiliate operates DG outside of its own territory.

Texas

Texas is praised for having a streamlined, workable statewide interconnection agreement and procedures, applying to DG generators of 10 MW or less. Texas has also streamlined the process by which small generators sell power into the grid. Texas addressed interconnection procedures quickly, while deferring standby rates and rate design until a later proceeding. Texas electricity is fully unbundled and utilities may not own generation, including DG. Texas varies from Maine in several important ways: first, Texas badly needs additional generation to serve its load, and second, the State forms a single bulk power system administration area, eliminating the complexities of dealing with multiple state interests.

New York

New York also has rules requiring a streamlined, workable statewide interconnection agreement and procedures. However, they apply to generation of only 300 kW or less. NY also badly needs more generation capacity, but the shortage is often locational in nature. New York allows a utility to own DG when it is needed to support the grid but does not allow utility ownership of DG that provides generation for a single customer. NY allows a utility's affiliate to own DG.

California

California investigated all distributed generation issues more comprehensively and over a multi-year time frame. California divided issues into two phases. Phase 1 includes interconnection standards, ownership and control of DG, DG planning, valuation and net metering, and education and outreach. Phase 2 addresses rate design, stranded costs, and distribution wheeling.

IEEE

As discussed earlier in this report, IEEE is currently developing national standards governing the interconnections between a utility grid and a distributed generator, which will likely form the basis for most states' procedures.

DOE

In March 2000, the U.S. Department of Energy (DOE) launched the Distributed Energy Resources Task Force, to encourage the development and adoption of DG technologies. DOE's near term goal was to address institutional barriers that interfere with DG adoption; a longer term goal is to meet 20% of the nation's generating capacity additions with DG by the year 2010.[27] DOE emphasizes the cleanliness, reliability, and affordability of distributed resources. In December 2000, DOE announced its Strategic Plan for Distributed Energy Resources, with the goal of developing "next generation" DG technologies and further addressing institutional and regulatory barriers in six strategic areas.[28]

Unique Conditions in Maine

Maine possesses some unique characteristics that make it dissimilar to states that are actively encouraging DG (i.e., New York, Texas and California). These conditions were discussed earlier in this report, and are reiterated here by way of comparison with other regions.

First, Maine is not capacity-short. The states that are most active in developing DG-friendly procedures are doing so because they need capacity quickly

Second, Maine does not have significant internal transmission constraints. Some states actively developing D.G. are doing so to supply electricity to load pockets into which transmission is constrained. New York City is the notable example.

Maine utilities have divested all generation. By comparison, many states allow utilities to own generation. In these states, the utility can carry out DG pilot projects, invest in grid-support applications, and buy back excess generation from customer-owned DG.

Most emerging DG technologies are fueled by natural gas, but many parts of Maine have no access to natural gas. This is changing, however. The past year has seen extensions or relatively firm plans for extensions to a number of towns and cities including: Windham, Bucksport, Old Town, Veazie, Bangor, Brewer, Sanford, Kittery, Orono, Brunswick, Pownal, Rumford, and Gorham.

In fact, it is possible that DG will hasten the extension of gas mains to unserved parts of the state. Generally, the gas utilities look for one or two large anchor customers before committing to extend their pipes to a new area. New DG facilities could serve as anchor customers. As a result, some Maine communities may welcome DG as a means to obtain natural gas service for much of the community.

Finally, larger-scale cogeneration is well established in Maine. Customers, utilities, and policy makers have more experience with the advantages, risks, and procedures that are relevant to the newer DG applications

[27] DOE's definition of DG is broader than this report's definition, and includes energy efficiency.

[28] See www.eren.doe.gov/der.

than do the stakeholders in many other states. This suggests that, as DG technologies become economically viable, implementation and policy development may occur relatively more easily in Maine than in some states.

XI. SUMMARY

This report summarizes issues that are currently under discussion nationally and in Maine regarding the benefits, risks and barriers connected with the use of DG. The report does not reach conclusions or make recommendations. Policy makers should use this report as a primer, to begin understanding DG-related issues. In October 2001, the Commission will submit a report directed by the Legislature that will offer recommendations for resolving or pursuing the issues identified in this report.

APPENDIX 1

STATE OF MAINE

—

IN THE YEAR OF OUR LORD
TWO THOUSAND

—

H.P. 1691 – L.D. 2397

Resolve, to Require and Examination of Distributed Generation

Sec. 1. Examination of distributed generation. Resolved: That the Public Utilities Commission shall undertake an examination of the issues related to existence and likely spread of the availability and use of local electric generation designed to serve the electrical demands of a single person or a small group of persons within a localized geographic area, referred to in this resolve as "distributed generation." The commission shall examine at least the following:

1. The nature of distributed generation technologies currently available and those in development;

2. Potential impacts on transmission and distribution utilities and their customers;

3. System planning impacts both in the short and long term;

4. The extent to which current law authorizes, limits and affects the use of distributed generation;

5. Safety issues raised by interconnection of distributed generation to transmission and distribution systems; and

6. Policy issues and options related to the following:

   A. Use of distributed generation by transmission and distribution utilities in lieu of line extensions;

   B. Use of competitive pricing for distribution services;

C. Allowing transmission and distribution utilities or affiliates of transmission and distribution utilities to be directly involved in the distributed generation business;

D. Appropriateness of standby rates and station service rates for customers using distributed generation;

E. use of net billing and metering arrangements; and

F. Regulation of interconnection; and be it further

Sec. 2. Report. Resolved: That the Public Utilities Commission shall issue a report to the joint standing committee of the Legislature having jurisdiction over utilities and energy matters no later than October 1, 2001 of its findings and recommendations resulting from its examination pursuant to section one of this resolve; and be it further

Sec. 3. Authority to report legislation. Resolved: That the joint standing committee of the Legislature having jurisdiction over utilities and energy matters may report out legislation on distributed generation to the First Regular Session or the Second Regular Session of the 120th Legislature after receiving the final report of the Public Utilities Commission pursuant to section 2 of this resolve.